STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2004-339

November 24, 2004

PUBLIC UTILITIES COMMISSION
Investigation into CMP's Stranded Cost
Revenue Requirements and Rates

BENCH ANALYSIS
[REDACTED]

I. INTRODUCTION

The Advisory Staff submits this Phase II Bench Analysis to present its independent analysis on certain issues (e.g. cost of capital) as well as providing the parties with its view, at this point in the case, on other ratemaking and policy issues as a means to facilitate the processing of the case.

As we have in prior bench analyses, the Advisory Staff notes that any views and positions expressed here are preliminary and based on the information presented to date. The final recommendations in the case will be presented in the Examiner's Report, and will be based on the record developed at the hearings scheduled in January.

II. DEFERRALS

A. Standard Offer Reconciliation.

In its Phase I filing, CMP as part of its proposal to reconcile the standard offer over-collection, included $2.89 million in internal costs, which it claimed were related to the administration of the standard offer. Included in this overall figure were $132,540 of internal labor associated with energy trading, $453,101 for legal costs, $586,088 for a revenue lag adjustment, and $200,147 for costs related to the PUC and OPA assessments. The Staff addresses each of these items below.

1. Internal Labor

In the Staff's Phase I Bench Analysis, the Staff recommended against the inclusion of the internal labor costs, since we believed that sufficient amounts were already included in the Company's rates for such activities in Docket No. 97-580 and, thus, such amounts were not incremental. In its Phase II filing, the Company stated that it agreed with the Staff and had removed those costs.

Subsequently, as part of its response to EX-04-21, the Company stated that it had reconsidered its position and based on the Commission's Accounting Order in Docket No. 97-596 which addressed incremental restructuring costs, the Company believed it was entitled to 50% of its internal labor costs or $67,125. Given the level of the request and the language in the Commission's past Order, the Staff is prepared to accept the Company's revised position as reasonable, subject to verification that the activities performed were in fact on standard offer related matters.

2. External Legal Costs

As noted above, CMP included $453,101 in legal costs related to CMP being the standard offer provider in its Phase I filing. In its Phase II filing, CMP removed $119,000 for legal expenses associated with litigating a dispute involving a large customer's supply service.

In addition to the Company's Phase II adjustment, the Staff would remove as not being related to the provision of standard offer, legal expenses billed from CMP's Washington, D.C. counsel Huber, Laurence and Abel, of $243,249.33 for costs primarily associated with litigating ICAP issues at FERC. While such costs may have been incurred while CMP was standard offer provider, in Staff's view they are not directly related to CMP's acting as the standard offer provider, but rather are related to CMP's interests in minimizing end-users' electricity costs as T&D provider. The Staff is prepared to accept this remainder of the amount included as legal expenses subject to verification that the costs were in fact related to CMP's being the standard offer provider.

3. PUC and OPA Assessments

CMP has included $200,147 as costs related to increases in its PUC and PPA assessments caused by its being standard offer provider. In the Staff's Bench Analysis, we noted that although CMP included standard offer revenue in its assessment calculation, other utilities did not. Under the provisions of 35-A M.R.S.A. § 116, a utility's assessment is based on "intrastate gross operating revenues" which is defined as intrastate revenues derived from a filed rate. It would thus appear that CMP erroneously included the standard offer revenue in its assessment calculation since standard offer is not provided pursuant to tariffs or filed rates. As noted in the Phase I Bench Analysis, since the overall electric utility assessment is constant, to the extent that CMP over-paid its assessment, other utilities were undercharged. In the Staff's Phase I Bench Analysis, we recommended that to the extent CMP's assessment was erroneous, this error be corrected as part of the assessment process.[1]

The Staff does not believe that CMP’s erroneous inclusion of standard offer costs in the assessment constitutes an incremental costs related to the provision of standard offer service to be collected from its ratepayers.

[1] 35-A M.R.S.A. provides that:

> D. The Commission may correct any errors in the assessments by means of a credit or debit to the following year’s assessment rather than reassessing all utilities in the current year.

4. Working Capital

In response to ODR-02-04, the Company provided the back-up for its $586,088 adjustment for working capital. At the technical conference held on November 10, 2004, the Staff asked the Company to reconcile its working capital adjustment with the fact that it was over-collecting its standard offer costs from ratepayers. The Staff's concern was that since the Company was over-collecting on standard offer during the course of the period it was acting as the standard offer provider was essentially playing with "house money" and a working capital allowance may not be appropriate. The Staff's concern was the subject of an additional Oral Data Request which the Company responded to on November 22, 2004. At this time, the Staff has not been able to work through the numbers as represented in the Company's response.

B. Champion Weekend Generation

As described in CMP's Phase II filing, due to an oversight in its metering and settlement systems, CMP did not properly account for weekend generation under the Champion PPA during the period May through November 2002. When the oversight was discovered by Champion in early 2003, although CMP was still obligated to pay Champion for the generation back to May 2002, it was beyond the time allowed by the market settlement rules to fully credit the account of the entitlement purchaser, Constellation. As a result, CMP had to pay Champion for power for which no entitlement revenue was received.

CMP indicated the cost of this power to be about $120,000. Because the power is purchased at CMP's STEO rates, which are set based on the entitlement sale prices, there would have been no net cost if it had been properly accounted for and credited to Constellation.

In its Phase 2 filing, CMP updated its deferral for "Extraordinary Stranded Cost Variances from QF Output". (This deferral was discussed in our Phase I Bench Analysis at Pages 9 – 11.) CMP reflects $191,577 associated with Champion during the March 2002 – February 2003 rate year as an amount to be recovered from ratepayers by operation of the deferral mechanism. In Staff's view, this should be reduced by $120,000 so that ratepayers do not bear the cost of CMP's oversight.

C. SAPPI

We raised several concerns about CMP's calculation of this deferral in the Phase I Bench Analysis, such as the adjustment related to transmission revenue, that have not been fully answered by CMP and therefore remain to be addressed. In addition, for the reasons stated infra, in the QF Cost section, the deferral should not include any QF incentive mechanism payments.

D. Rate Mitigation for Certain Customers

The Staff noted in its Phase I Bench Analysis that because certain responses to data requests were still outstanding, it was not possible to verify CMP's calculations regarding the deferrals of the $0.003 and $0.0045 per kWh discounts given to certain customers or to quantify the effect of using actual, rather than forecast, sales to calculate the deferral for the $0.003 per kWh discounts. The Phase I Bench Analysis indicated that these issues would be addressed in the Phase II Bench Analysis. However, because the necessary data response was only very recently received, and because that data response appears to suggest that the Company has changed its estimate of the $0.003 per kWh deferral, it will be necessary to address these issues in a later filing.

E. Non-Core Price Change Deferral (July 1, 2003 – February 28, 2005)

The Staff noted in its Phase I Bench Analysis that CMP calculated the amount of the non-core price change deferral by using bundled rates rather than stranded cost rates. The Phase I Bench Analysis indicated that this matter would be addressed in the Phase II Bench Analysis. However, additional review of the recently filed data responses is necessary before the effect of this issue can be quantified. Therefore, this matter will be addressed in a later filing.

III. LEVELIZATION AND RECONCILIATION MECHANISMS

In the Phase I Bench Analysis, the Staff proposed that as part of this stranded cost rate proceeding, the Commission adopt a full reconciliation mechanism which would include both stranded costs and revenues generated from stranded costs rates. The Staff continues to believe that this is the correct approach here.

In its Phase II filing, the Company presented two different revenue requirement scenarios. The first which would set rates in each of the next three years so that each year's rates recover that particular year's revenue requirements. Based on CMP's current rate proposals and the current QF entitlement sales proxy supplied by Staff, CMP projects stranded cost revenue requirements to be $144 million, $128 million and $111 million during the next three years. The other alternative was to levelize the revenue requirements over the next three years and set rates to recover this levelized revenue requirement. As part of its filing, CMP indicated that if this second approach was taken a reconciliation mechanism should not be adopted. In response to EX-04-17, CMP explained that it would be possible to utilize a reconciliation approach with a levelization approach if the rate-setting period did not go beyond 3 years and provided that carrying costs were done properly.

Given the likelihood that standard offer rates will increase significantly for CMP's residential and small customers in March, 2005, the Staff supports CMP's three-year levelization approach. The Staff also agrees with CMP that a 3-year period is an appropriate time period to set the levelized revenue requirement. In the Staff's Phase I Bench Analysis, the Staff recommended that the carrying costs or assets be deferred during the reconciliation be based on the short-term treasury bond rate depending on the period of deferral. This approach assumed that the Company had no stranded rate base going into the reconciliation period. The Staff agrees with CMP that should the three-year levelized approach be utilized, an appropriate carrying cost on the regulatory asset as a result of the levelization should be allowed. We believe that this rate would be higher than the T-Bill rate proposed in our Phase I analysis and should be based on the Company's weighted average cost of capital (WACC) set for its stranded cost rate base based on current financial market conditions and accounting for the fact that the Company's risks have been reduced as a result of reconciliation. The Staff recommended WACC on what we call the structural stranded cost rate base is in Section IV of the Bench Analyis.

Should the Commission adopt a reconciliation mechanism, the staff would recommend that the ground rules to cover the reconciliation be explicitly set forth up front. In this regard, the Staff would recommend that as part of the Commission's Order, it first be made clear that reconciliation does not mean a pure flow-through and preclude the Commission from considering the prudence of a utility's actions in determining what costs (or discount revenues) are recovered from ratepayers. Second, only items approved and included in stranded costs revenue requirements should be conditions for automatic reconciliation. Other items would require specific approval by the Commission to determine both that they are first, appropriate for recovery as a stranded cost item and second, that they were prudently incurred. Third, the revenue requirements and sales authorized in this case should be tracked against actual values. Differences between these amounts should receive carrying costs on the short-term carrying charge rate which Staff continues to recommend be based on our Phase I Bench analysis. The Staff would anticipate that the reconciliations be done on an annual basis in coordination with any updates in stranded cost revenue requirements resulting from sales of the Company's QF output.

IV. Cost of Capital

Summary

Recognizing that CMP's current Return on Equity (ROE) of 10.50% and Weighted Average Cost of Capital (WACC) of 12.22% are extremely outdated and that the most current analyses available for the ROE of a T&D electric utility in Maine are those filed in BHE's stranded cost Docket No. 2004-112, we recommend using those analyses to set the ROE on the rate base "levelizer" in CMP's stranded cost filing. For expense deferrals, we continue to believe that the methodology set forth in our Phase I Bench Analysis in this Docket is appropriate. That methodology treats these items like debt instruments and, depending on the timing of the reconciliation mechanism, uses the appropriate Treasury security (one-year and three year have been discussed) plus the interest margin commensurate with a "Triple-B" bond rating to determine the carrying cost. If the Commission chooses not to adopt that approach, our recommendation is to use the ROE that we recommend here as opposed to one dating from a late-1997 to early-1998 time frame as CMP recommends.

In BHE's Docket No. 2004-112, we used an analysis filed by Company witness Dr. Robert Strong in reaching our own preliminary recommendation because he used many of the same methodologies that Commission Staff has used and that the Commission itself has accepted in the past.[2] As we noted there, Dr. Strong relied primarily on the Discounted Cash

[2] We note that we are not discounting the analysis provided by OPA witness Stephen Hill in either this Docket or in Docket No. 2004-112. Mr. Hill's analysis was

Flow (DCF) model as the basis for his findings; he evaluated and constructed peer groups of "similar" companies, used financial data sources that are familiar to the Commission and he made an adjustment for flotation costs. It was therefore not necessary for the Advisory Staff to conduct a comprehensive independent analysis. We instead made a number of adjustments (such as adding and removing companies from peer groups) and corrections to what we believed to be data errors in his calculations to derive our preliminary conclusion.

Corrections and adjustments aside, we believe that Dr. Strong's final recommendation in that case (an 11.10% return on equity) overstated the risks faced by an electric utility focused on the transmission and distribution (T&D) segment of the industry.[3] We believe that the T&D segment of the electric utility industry has a relatively low business risk profile and that opinion is echoed in the credit reports provided by the Company in response to OPA Data Request 03-05. We believe that there are two possible ROE/WACC outcomes for CMP depending on whether a reconciliation mechanism for the sales forecast is adopted in this case. Assuming that there is reconciliation, the appropriate all-in ROE for BHE as a T&D electric utility is 8.00% and, using our own estimated capital structure for CMP, a resulting pre-tax WACC of 9.72%. In the absence of reconciliation, we would recommend an ROE of 8.65% with a resulting pre-tax WACC of 10.23%.

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filed on the same day as our Bench Analysis and the discovery process there has just been initiated.

[3] Dr. Strong's testimony is attached to this document as Appendix A.

A. Corrections to Input Errors

It is important to recognize that Dr. Strong's ROE recommendation of 11.10% in BHE's Docket No. 2004-112 was derived from Table 14 of his testimony. In order to arrive at 11.10%, Dr. Strong chose the mid-point between the *mean* and *high* estimates of the DCF results shown there. Dr. Strong chose this point because he believed that the equity ratios of the peer group companies are sufficiently higher than that of BHE such that BHE would therefore have a higher total risk profile than that of the peer companies thus warranting a upward adjustment in ROE. We have re-created that table below:

Dr. Strong's Table 14

Comparison Group	Low Estimate	Mean Estimate	High Estimate
Water Companies	9.76%	10.86%	11.79%
Electric Companies	7.57%	8.80%	10.33%
Gas Companies	7.43%	9.83%	13.62%
Average	8.25%	9.83%	11.91%

As noted in Dr. Strong's testimony on page 17, the average of 9.83% and 11.91% is 10.87%, and adding 0.19% for flotation costs yields an all-in total ROE of 11.06% (which is then rounded to 11.10%) for BHE. We believe that there are significant corrections required in Dr. Strong's Tables 6 and 9 that flow through to Table 14, that have a considerable effect on his calculations.

Table 6 (Electric Companies Indicated Cost of Equity) of Dr. Strong's Testimony appears to contain a number of input errors that leads to an erroneous range of estimates for the Electric Utility peer group. Specifically, the dividend yields and growth rates that appear in Table 6 are not the same ones calculated in preceding Tables 4 and 5 and thus all the final Cost of Equity numbers appear to be incorrect. Taking DQE as an example, the current dividend yield shown in Table 4 was 5.29%. Dr. Strong then calculated the average growth rate shown in Table 5 for DQE as 4.50%. However, neither of these figures appears on Table 6. Instead, Table 6 shows a current yield of 5.03% and a dividend growth rate of 5.17% for DQE leading to an ROE estimate of 10.33%. This miscalculation occurred for every company in the electric peer group.

We have recalculated Table 6 in Advisors Exhibit COC-2, and the corrected results are shown in the box in the lower right titled "Statistics without UIL."[4] This shows a range of ROE estimates between 7.97% and 9.91% with an average, median and midpoint of 8.97%, 9.02% and 8.89% respectively. As we will show later in this report, these changes impact Table 14.

Table 9 of Dr. Strong's Testimony, titled "Natural Gas Companies Indicated Cost of Equity" appears to have similar errors to those encountered in Table 6 in that dividend yield and growth estimates derived on Tables 7 and 8 for AGL Resources, Laclede Group and People's Energy did not properly transfer to Table 9. In addition, we believe that neither Southwestern Energy nor Southern Union Gas should have been included in this peer group

[4] Dr. Strong excluded UIL from his electric utility peer group. We will explain why we chose to include UIL in the electric utility peer group later in this report.

as our research indicates that neither company currently pays a dividend, nor have they paid one for quite some time.[5]

This is significant because these two companies define the two highest ROE point estimates for the peer group (Table 9, column 5) at 11.52% and 13.62% respectively. Making the corrections noted above for data input errors and omitting Southwestern Energy and Southern Union Gas from the peer group yields the results shown in the box titled "Statistics without Expansion" in the lower right of Advisor's Exhibit COC-3.[6] Therefore, instead of the range of ROE estimates of 7.43% to 13.62% (with a 9.83% average) shown on Dr. Strong's Table 9, we believe that the correct range is 7.06% to 9.83%, with an average, median and midpoint of 8.58%, 8.54% and 8.44% respectively.

C. Peer Group Adjustments

It is our view that all three of Dr. Strong's peer groups require additional adjustments beyond the appropriate exclusion of Southwestern Energy and Southern Union Gas from the natural gas peer group. Dr. Strong excluded UIL Holdings (electric), Cascade Natural Gas, Chesapeake Utilities (gas) and American States Water from their respective peer

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[5] The September 17, 2004 issue of *Value Line* indicates that Southwestern Energy last paid a common dividend for the quarter ended June 30, 2000 (page 452) and that Southern Union's common dividend was suspended prior to the year 2000 (page 473).

[6] We will explain why we expanded this peer group later in this report.

groups because the sources he used for long-term earnings growth rates (Zacks and/or Yahoo! Finance) indicated that there was only one long-term analyst forecast for each of these companies. It has been common practice for Advisory Staff (and the Commission) to exclude companies that have *no analyst forecast* of long-term earnings growth, but we are virtually certain that we have not previously excluded companies that had only a single earnings forecast. We therefore see no justification for making this exclusion and thus we have added these companies to the appropriate peer groups.

We have also added Piedmont Natural Gas to Dr. Strong's natural gas peer group because we are unable to determine why it was excluded originally. Dr. Strong's response to Examiner's Data Request 04-01 indicates that it was excluded because less than 67% of total revenues were derived from gas sales. The Commission's November 2004 copy of *C.A. Turner's Utility Reports* indicates on page 15 that 77% of Piedmont's revenues are derived from gas sales. We have also determined that there is no merger pending for Company, that it pays a common dividend and that there are long-term analyst earnings forecasts available (per Yahoo! Finance).

After making the corrections and peer group adjustments noted above, Dr. Strong's Table 14 would appear as follows:

Adjusted Table 14

Comparison Group	Low Estimate	Mean Estimate	High Estimate

Water Companies	6.80%	10.28%	11.79%
Electric Companies	7.04%	8.69%	9.91%
Gas Companies	7.06%	8.58%	9.83%
Average	6.97%	9.19%	10.51%

If one accepts Dr. Strong's premise that the appropriate ROE for BHE lies midway between the mean and high ROE estimates shown on Table 14 due to BHE's relatively low equity ratio, that number falls over 100 basis points to 9.85% before flotation costs (averaging 9.19% and 10.51%). We did not accept this premise for BHE and our calculations indicate that if anything, an adjustment in the opposite direction might be warranted for CMP. The numbers in this adjusted table are calculated on Advisor's Exhibits COC-2, COC-3 and COC-4.

D. Risk Assessment of BHE versus Peer Groups

Dr. Strong's recommended an ROE well above the middle of his range for BHE due to a perceived difference in the common equity ratio of BHE as compared to the peer group companies. This difference is illustrated by data shown in Tables 11, 12 and 13 of his testimony. These tables substantially overstated the actual common (and total) equity ratios of Dr. Strong's peer group companies because they appeared to use market values for common equity rather than book values and those market values exceed their respective book values by a wide margin. We do not believe it is appropriate to use market value of common equity for ratemaking purposes.

Advisor's Exhibit COC-6 shows what we believe to be the appropriate numbers for the comparison of common equity ratios. This table was created using *C.A. Turner's Utility Reports* definition of the common equity ratio for the quarter ended June 30, 2004. Based on our calculations it appears that as of June 30, 2004 that CMP's common equity ratio net of goodwill, was approximately 47%, which is what was allowed in the Company's "MegaCase," Docket No. 97-580 Therefore, CMPs common equity ratio was significantly higher than the average (40.7%) and median (40%) of Dr. Strong's electric peer group and also exceeded the average and median common equity ratios of the natural gas, water utility and the three combined groups (which are in the 45% - 46% range).

E. Flotation Costs

Dr. Strong chose to include a 19-basis point increment for flotation costs in his final recommendation for BHE. For a number of reasons we believe that flotation costs are in fact lower for CMP.

Since this issue was last addressed in CMP's "Mega-Case" (Docket 97-580 Order at 56-57), the Company was acquired by Energy East. We expect that one merger benefit that would accrue to CMPs ratepayers is a lower cost for the issuance of common equity. Energy East, being larger than CMP, would likely issue equity in larger blocks than would CMP thus reducing issuance costs. Indeed, Dr. Strong provided a regression analysis suggesting that the size of an equity issuance does influence the cost of issuance in an inverse manner.

We have also not yet explored whether Energy East has a dividend reinvestment program. The existence of such a program would provide Energy East (and thus CMP) a very low cost source of new equity investment. This should be accounted for in any flotation cost adjustment.

A final observation is that Dr. Strong's regression analysis did not consider other factors such as the effect that overall risk profile of the issuer would have on issuance costs. We believe that issuance costs may be affected by the risk of the issuer and in his response to a Data Request on this matter (Examiner's 04-16 (b)), Dr. Strong did not discount that possibility.

For simplicity, we have at this point used 3.0% increment for CMP's equity flotation costs as the Commission did in Docket No. 1997-580. On Advisor's Exhibit COC-5, that increment translated to roughly a 10-basis point increment using the low-end result from the table. We chose the low end result because the 3.00% cost adjustment was developed prior to CMP's acquisition by Energy East and without any attempt to account for a dividend reinvestment program.

F. Capital Structure

For the purpose of this analysis, we have used CMP's June 30, 2004 capital structure per the Company's quarterly 10-Q filing with the SEC for determining CMP's WACC on Advisor's Exhibit COC-1. We adjusted out Goodwill of approximately $325 million from the Company's common equity balance, leaving a total of $330.4 million (resulting in a common equity ratio 46.7%). We also included June 30 balances for preferred equity, long-term debt (including current maturities and capitalized leases) and short-term debt, for a total capitalization of $707.1 million.

The cost rates for individual capital components were taken from CMP's responses to OPA Data Requests 03-02 and 03-06. For preferred equity, we accepted the Company's estimate of 4.60% (per attachment 2 to OPA 03-02) and for long-term debt we used 6.47% (per attachment 1 to OPA 03-02). CMP also showed an embedded debt cost of 7.15% on its worksheet, however that figure appeared to be associated with a long-term debt balance of approximately $231 million. The 6.47% rate appeared to be associated with balances of approximately $275 million and we determined that the Company's June 30, 2004 long-term debt balance was just over $316 million. We therefore chose to use the rate associated with a balance closer to what we believe to be the actual balance.

In order to derive a cost rate for short-term debt balances, we relied on CMP's response to OPA Data Request 03-06. On Attachment 3, page 1 of 10 to that response, CMP indicated that between December 2003 and October 2004 that it paid an average rate of approximately 1.92% on short-term debt. Over that period, we found that the one-month LIBOR Rate was approximately 1.48%, indicating that CMP's spread to the LIBOR index was around 0.44% (or 44 basis points). We then used the November 2004 issue of *Blue Chip Financial Forecasts* to determine a "consensus" forecast of the LIBOR index for the end of 2004 and for all of 2005. Blue Chip only provides a forecast for the Three-Month LIBOR Index, so there is likely to be a slight mismatch of indexes, but that forecast yielded an average three-month LIBOR rate of 2.86% for the next fifteen months. Adding the 0.44% borrowing margin for CMP to the index, indicates an average short-term debt rate of 3.30%, which is shown on Advisors Exhibit COC-1.

G. Conclusion

We believe that Dr. Strong's peer groups, as adjusted provide a reasonable basis for determining an appropriate ROE for CMP. Advisor's Exhibit COC-1 indicates that the measures of central tendency (average, median, midpoint) for the electric and gas peer groups tend to cluster in the 8.50% to 8.70% range and we rely primarily on those peer groups for our final recommendation. The water utilities exhibit a somewhat wider range of expected ROEs, but we are concerned that the growth rates in the water industry are not as representative of the growth prospects of T&D segment of the electric industry as are the growth rates associated with the electric and natural gas peer groups.

Value Line indicates that much of the growth of companies in the water utility industry stems from more stringent requirements in *Safe Drinking Water Act* (SDWA). With many small water utilities lacking the internal and/or external funding sources for compliance with SDWA, merger and acquisition activity has increased considerably in the industry suggesting that earnings growth for the larger water utilities is based on merger savings rather than internal growth (see *Value Line* of October 29, 2004, page 1420).

These larger water utilities are precisely the ones that are used in our water utility peer group and their earnings growth rates are noticeably higher than those of the electric utilities (which have primarily a T&D focus) or the natural gas LDCs. This is plainly evident on Advisor's Exhibits COC-2, COC-3 and COC-4, where the electric groups earnings growth rates cluster in the 3.8% to 4.2% range, the natural gas earnings growth rates cluster in the 4.1% to 4.3% while the water utility earnings growth rates are in the 6.1 % to 7.0% range. We suspect that these growth estimates may be driven by acquisition activity in the industry and therefore cannot weight them as heavily as the electric and gas peer groups in our final recommendation.

We believe that the reasonable range for the ROE of CMP as a T&D utility is between 8.00% and 9.40%, with a midpoint of 8.65% inclusive of a positive 10-basis point adjustment for common equity flotation costs. As shown on Advisors Exhibit COC-1, assuming that a reconciliation mechanism is adopted for the sales forecast, we recommend that CMP's stranded cost rates be determined using the lower end of that range, or 8.00%. If no such mechanism is adopted, we would recommend using the middle of the range, or 8.65% for ratemaking purposes.

In order to determine the lower end of our reasonable range, we have chosen the 1rst quartile point of the electric utility peer group results or 7.85%. This is the point half way between the low end of the indicated electric utility range (7.04%) and median point of the range (8.65%). Adding 10-basis points for flotation costs raises that number to 7.95%, which we then rounded to 8.00%. We noted previously that CMP has a common equity ratio that is significantly higher than that of the electric utility peer group and when that measure of financial risk is combined with the low business risk environment alluded to by the credit rating agencies, we believe that the total risk profile of CMP falls below the middle area of the range indicated by the electric utility peer group. We therefore believe that a downward adjustment is warranted for CMP.

With the measures of central tendency for the electric and natural gas peer groups clustering in the 8.50% to 8.70% range, we believe that in the absence of a reconciliation mechanism, that CMP should be allowed no higher than 8.65%. Although we have largely discounted the results from the water utility peer group, if we chose to incorporate the mid-point of the water utility range (at 9.40% which coincides with a 6.1% earnings growth forecast and includes a flotation cost adjustment) as the top end of a reasonable range for CMP, and combined that with our low-end estimate of 8.00%, that also suggests 8.65% as a reasonable middle area for CMP.

V. SALES FORECAST

A. Overall Approach

As noted in our Phase I Bench Analysis, the Staff is recommending that stranded costs revenues be reconciled on a going forward basis as part of an overall stranded cost reconciliation mechanism. Although no agreement has been reached to date, the Staff is hopeful that this issue will be resolved and needless litigation on the sales forecast can be avoided.

B. Residential Issues

Company's witness Mr. John Davulis, has employed an econometric model to forecast CMP's residential and commercial sales. His model currently projects residential sales rising from 3,308 million kWh in 2003 to 3,577 million kWh by 2008, a cumulative annual average growth rate of 1.6% per year.

In the Staff's Bench Analysis in Docket No. 2002-770, the Staff expressed its concerns that the Company's end use residential model was under-forecasting sales. Based upon our review of CMP's sales to the residential class since that time, such concerns have not dissipated. See Response to EX 02-02 attached as RR-1. Staff Exhibit RR-2 shows that over the past five years (1999-2003) CMP's residential kWh sales have been growing at an average annualized rate approaching 3.7% and 2004 is on a pace to approach that rate. Over the same stretch, residential customer growth was just over 1.3% annually, indicating that in recent years despite DSM efforts and improvements in the efficiency of appliances, average usage per customer is increasing. In Docket No. 2002-770 the Staff recommended that a simple trend analysis appeared to be a better method to project residential sales. Actual sales data available to date would seem to confirm this belief.

In Docket No. 2002-770, one of the major criticisms of the Staff's approach was that it did not correct for the effects of weather. The Staff accepts this criticism and would thus adjust the five-year trending analysis for the effects of weather based on HDD and CDD data for the past 15 years. In the past, Dr. Estomin, the OPA's witness has included a weather normalization variable in his econometric equation. After reviewing such data, the Staff will assess the appropriateness of using such a variable to perform the weather adjustment we suggest.

The Staff would also note that in Docket No. 2002-770, the Staff suggested several changes in the ways that Mr. Davalis accounted for the effect of DSM. It appears based on the CMP Phase II filing, that Mr. Davalis has accepted a number of the Staff's suggestions. Based on the information provided by Efficiency Maine and with the Company adjustments the Staff, at this time, accepts the Company's residential DSM adjustment.

We, therefore, propose using the historical trend of residential sales for the five most recent years, normalized for weather and adjusted for DSM as proposed by the Company in its Phase II filing as the residential forecast sales to be utilized in this case.

C. Paper Sales

The Company has adjusted paper sales for the loss of the large customers during the three-year period.

D. Forecast Non-Core Revenues

The Company has estimated approximately $10.4M per year in revenues from non-core sales over the rate effective period. If the Commission adopts a mechanism that reconciles the forecast and actual non-core revenues, questions regarding the accuracy of the Company's estimate of these non-core revenues are largely moot. However, absent such a mechanism, the Company's estimates should be refined.

In order to maximize the revenues from such contracts, it is necessary to evaluate the viability and cost of a customer's alternative and then, taking the customer's cost of supply service into account, offer the least amount of discount necessary to retail the load. In developing its estimates of the non-core revenues, the Company failed to make any such evaluations but simply assumed the existing contracts would continue at the existing contract rates. According to the Company, this is reasonable, even in light of significant changes in both supply prices and the cost of fuel for alternative generation, for two reasons. First, the Company asserts that changes in supply costs and alternative generation's fuel costs tend to track together, thereby offsetting each other in a comparison of the economics of the contract versus the alternative. Secondly, the Company indicated that the contract price is as good a proxy for the actual price as any other estimate until a more thorough analysis is made at the time the contract is renegotiated.

We disagree. While it is true that supply prices and fuel prices tend to track each other, the relationship between the two prices is a general trend, not a one-to-one relationship. For example, market supply prices tend to be driven primarily by the cost of natural gas, whereas the alternative for many customers is diesel fuel. Moreover there are many factors that can disrupt the relationship between the two prices. For example, the amount of discount necessary to keep customers with multiyear supply contracts from pursuing their alternatives may have decreased in light of the significant increases in fuel costs over the last several years. Further, customers' abilities to install alternative generation sources can be affected by other factors such as a customer's overall profitability and ability to obtain capital. These factors should be considered, at least in a general way, prior to setting non-core revenues, if those revenues are not to be reconciled.

VI. QF-RELATED COSTS

A. Merimil

B. QF Incentive Payments – SAPPI

Prior to Electric Restructuring, the SAPPI PPA operated to produce a "wash rate" so that the cost of the power bought from SAPPI's predecessor-in-interest, S.D. Warren Company, equaled the cost of power sold to S.D. Warren. The Commission approved the 1990 PPA amendment that produced this "wash rate" concept in reliance on the representations of the contracting parties that ratepayers would essentially be financially neutral as a consequence of the wash rate. *Supplemental Order,* Docket No. 90-076, at 8-17 (May 15, 1991). Thus, prior to March 1, 2000, the SAPPI PPA cost ratepayers zero dollars on average on a net basis.

Since March 1, 2000, CMP estimates that the SAPPI contract cost ratepayers more than $14 million from March 1, 2000 to Feb. 28, 2001 (Year 1) and more than $32 million from March 1, 2001 to Feb. 28, 2002 (Year 2). (ODR-04-13) In Years 3 through 5 (March 1, 2002 to Feb. 28, 2005), CMP estimates that the SAPPI PPA cost about $2 to $3 million per year. CMP estimates that the SAPPI PPA will cost ratepayers each year in the remaining years of the PPA (through 2012) about $2 to $3 million per year. CMP now asserts that, as a result of the 2001-332 stipulation, paragraph 19 “QF Incentive Mechanism,” it is entitled to about an additional $1 million per year from ratepayers because CMP and SAPPI agreed to amend the PPA in 2002.

In our Phase I Bench Analysis, the Advisors stated that the SAPPI PPA amendments were not intended to be a QF contract restructuring eligible for an incentive payment pursuant to paragraph 19 of the Docket No. 2001-232 Stipulation. In its Oct. 13, 2004 Rebuttal to the Phase I Bench Analysis, CMP disagrees with the Advisory Staff’s position concerning the meaning of “QF contract restructuring.” CMP states that “it is reasonable to assume that the parties intended to give this term its natural and historical meaning.” CMP’s Oct. 13, 2004 Filing, Vol. IV at p. 28. The Advisors agree and believe that in determining the “historical meaning” it is relevant to review the development of QF incentive mechanisms since the Electric Restructuring Act was passed, especially as the issue was developed in Docket No. 2001-239.

In the so-called “megacase” (Docket No. 97-580) Phase I Order, an issue arose concerning whether and how future savings for QF restructuring should be estimated into CMP’s post-restructuring revenue requirement. CMP stated that, because such savings could not be precisely measured, the Commission should assume no savings would occur in the rate effective period. The Commission rejected CMP’s approach because an assumption that no savings would occur was contrary to CMP’s statutory obligation to mitigate stranded costs. The Commission stated that two approaches were acceptable, to reasonably estimate the savings or to defer the savings. The Commission decided to defer the savings:

> By deferring the savings associated with future QF contracts, the Commission can ensure that the actual savings will be passed through to ratepayers and that the Company will not recognize a windfall if it successfully restructures a contract. To ensure that CMP aggressively pursues all appropriate QF restructuring opportunities, we will allow the Company to retain 10% of the net savings resulting from QF buyouts or restructurings occurring after March 1, 2000.

Central Maine Power Company, Docket No. 97-580, at 110 (March 19, 1999). Although the March 19 Order yields no further elaboration of the term "QF restructuring opportunities," the Commission did discuss the OPA's concern that CMP was not devoting sufficient corporate resources to QF cost mitigation. In response to the OPA's concerns, the Commission agreed that CMP should continue to "aggressively pursue stranded cost mitigation through QF contract restructurings, as well as the sale of entitlements…" *Id.* at 112.

Subsequently, and in another docket, the Advisory Staff shared the concern about the amount of CMP resources devoted to QF restructuring. As part of the Docket No. 99-666 Bench Analysis (CMP's incentive rate mechanism or Alternative Rate Plan docket), the Advisory Staff recommended increasing the QF incentive mechanism so that CMP would retain 25% of the savings. The Advisors believed that it was not clear that 10% was a sufficient corporate incentive. Ultimately, the case was settled and the QF cost mitigation issue was not addressed further.

The Advisory Staff also raised the issue of QF cost mitigation in the first post-megacase stranded cost proceeding, Docket No. 2001-232. The issue was raised for the first time by the Advisors in their November 14, 2001 Bench Analysis. The Advisors pointed out that of the remaining 34 QF contracts, 25 had been previously restructured. In the post-Electric Restructuring time period, however, only two contracts had been bought out. The Advisors discussed that the CMP department that administered QF contracts also managed standard offer procurement and related negotiations, a function that required much more resources than anticipated in the planning stages of Restructuring. The Advisors acknowledged that CMP's efforts related to standard offer procurement were essential to the Commission. The Advisors observed, however, that it appeared that prior to Electric Restructuring, CMP was able to allocate greater corporate resources to the buyout/buydown QF cost mitigation effort. As CMP described the remaining QF contracts as more difficult to restructure, the Advisors were concerned that more corporate resources were needed rather than less to accomplish additional future contract restructurings. The Advisors concluded that it was not clear that merely increasing the percentage of savings retained by shareholders would have sufficient impact to make a difference.

Thus, the Advisory Staff introduced the issue of QF cost mitigation incentives into Docket No. 2001-239, because of its concern that CMP had not devoted much attention to the remaining, and more difficult to restructure, QF contracts. By November 2001, the SAPPI PPA dispute did not fit into this category. The amendment to unallocated section 6 of the Act (P.L. 1999, ch. 730) was passed in 2000, and the

Commission was directed to “equally apportion any resulting costs and benefits between the qualifying facility and the utility” if the “wash rate” could not be restored for both. The Commission could not be concerned in late 2001 that CMP needed an incentive bonus to sufficiently mitigate SAPPI PPA stranded costs. The dispute had been before the Commission for more than one year. If CMP proposed a PPA settlement that was not reasonable, the Commission could reject it and order a different resolution. Indeed, five months before, in Docket 2000-123, the Commission did reject a SAPPI-CMP PPA settlement as too risky from a ratepayer cost perspective.

In November 2001, the Advisory Staff knew that due to the ongoing litigation related to SAPPI and the Commission’s statutory authority to mandate an equitable result, ratepayers did not need to give CMP any incentive bonus, much less a larger one to protect them from inadequate stranded cost mitigation related to the SAPPI PPA.

In response to the Docket No. 2001-232 Bench Analysis, on December 2, 2001, CMP stated that incentives for QF contract restructuring were proper and suggested the Advisor’s ARP-proceeding proposal for a QF restructuring incentive of 25% was appropriate. Shortly thereafter, the stipulation was filed in Docket No. 2001-232, with the paragraph 19 provision calling for the 20% incentive for QF contract restructuring, or a 100% increase of the incentive the Commission put in place in the megacase. Given this history of the development of the QF incentive mechanism in the Docket No. 2001-232 proceeding, the Advisors maintain their position that no party logically or reasonably could have, believed that the resolution of the SAPPI-CMP PPA dispute could be a QF contract restructuring subject to the paragraph 19 incentive bonus.

In addition, the Docket No. 2001-232 Stipulation itself makes it explicit that the paragraph 19 incentive mechanism would not apply to SAPPI by providing in paragraph 20 for the deferral and late inclusion in rates of "any difference between actual costs and revenues under the SAPPI Somerset purchase power agreement and the costs and revenues assumed in setting rates." This provision is clear and unambiguous regarding what ratepayers were subject to related to SAPPI during the March 2002 – February 2005 period. The contract or statutory interpretation principle, that a specific provision takes precedence over a general provision, should apply and the SAPPI deferral should be calculated as described in paragraph 20, and not 19. Paragraph 20 also demonstrates an intent that the incentive payment should not be applied prospectively either.

Even if CMP is correct, and the resolution of the SAPPI-CMP dispute could be interpreted as a QF contract restructuring subject to paragraph 19, CMP is not entitled to any incentive. Paragraph 19 calculates the savings by subtracting the total post restructuring costs from the total costs that would have been incurred had no restructuring taken place. The QF restructuring in question results from the Third and Fourth Amendments to the PPA that were part of the stipulation that was approved by the Commission on June 28, 2002. *S.D. Warren Co., Order Approving Stipulation,* Docket No. 2000-123 and 2001-451 (June 28, 2002). CMP assumes that without this settlement, the Commission would have decided the SAPPI-CMP dispute in a way that ignored the possibility of a "net-load" result, that a "gross-load" result of an additional $7 to $8 million per year would likely result, and that the Commission would have equitably apportioned these costs by imposing all of them on CMP, and its ratepayers.

CMP's assumption about the total costs that it would have incurred if the SAPPI-CMP dispute was not settled are not reasonable and are not consistent with the litigation history of Dockets No. 2000-123 and 2001-451. The dispute had been before the Commission for more than two years. It was clear that the Commission would decide the matter, either by litigation or by approving a settlement. While it was probably clear before June 18, 2001, it was abundantly clear after, that the Commission took seriously its obligation in unallocated section 6 to equitably apportion the resulting costs and benefits, and would decide the dispute only after carefully considering how those costs and benefits were distributed. *S.D. Warren Co., Order Rejecting Stipulation,* Docket No. 2000-123 (June 18, 2001).

Even during the Summer of 2001, it was clear that no final Commission decision would be made until CMP and SAPPI had at least sought supplier bids on a "net load" basis. Indeed, the Commission rejected the stipulation on June 18, 2001 in part because it gave "[S.D.] Warren the unilateral right to reject a bid option that may minimize the cost spread if it decides that the result would impose unacceptable constraints on Warren's operation of the Somerset Mill." *June 18 Order* at 4. It seems clear that regardless of the CMP-SAPPI agreement in the Spring of 2002, the Commission would have required the parties to seek bids to supply a “net load” arrangement as part of the process to resolve the case. Given the ultimate resolution of the SAPPI litigation, it is reasonable to conclude that a successful bid would have been received, and the resulting cost of the net-load arrangements would have been similar as to the one that actually accrued. CMP’s QF “restructuring” with SAPPI resulted in an apportionment of all the additional costs imposed by the net load arrangement on CMP and its ratepayers, in return for SAPPI giving up its so-called windfall for Year 1. Had CMP and SAPPI not reached their 2002 Agreement, and thus, no “restructuring” taken place, a Commission ordered “equitable apportionment would likely not have resulted in higher costs to ratepayers because the CMP-SAPPI settlement had apportioned all costs to ratepayers. Thus, the CMP-SAPPI settlement can not be viewed as saving ratepayers any significant amount of money.

Electric Restructuring did not leave costs associated with the SAPPI “wash rate” PPA stranded. Unfortunately, Electric Restructuring resulted in costs that did not exist in the pre-Restructuring world. During the first two years of Restructuring, those costs were extremely high, and have been paid for ratepayers. The best possibility to mitigate the costs in the first two years was lost when the output associated with the PPA was sold as part of CMP’s Chapter 307 auction. CMP did not raise this matter before the output was sold and the opportunity for mitigation lost. However, we have not (and do not) take the position that CMP should be penalized for this oversight.

However, by 2000, the problem was understood. S.D. Warren brought the dispute to the Commission in February 2000. In April, the Legislature enacted the amendment to Unallocated Section 6, and gave the Commission the authority to equitably distribute the costs and benefits if both sides could no longer achieve a "wash." Although CMP worked hard throughout the litigation (and settlement discussions) to obtain a reasonable resolution, even if CMP and SAPPI did not enter into the Third and Fourth Amendments to the PPA in the Spring of 2002, it is likely that a similar result would have been imposed by the bid results and the Commission. Thus, there are not significant savings for CMP to share.

C. QF incentives payments Benton Falls

As an orphan decrement QF contract, the Benton Falls PPA was also not a "difficult" PPA to restructure, requiring an increased incentive to CMP. The dispute was already in litigation when the 2001-232 stipulation was reached. Given the history of the development of the "double" bonus incentive mechanism of that Stipulation, the Advisors continue to believe that the Benton Falls litigation settlement was not a "QF restructuring" within paragraph 19.

Even if the Advisors accept CMP's view that the Benton Falls settlement is covered by the incentive mechanism, no incentive should be due. At the technical conference, CMP confirmed that going into the litigation, it assessed its chances of winning at 50/50 (at least). Thus, it seems that the total cost of the no settlement option is similar to the total costs of settled results, producing a zero incentive payment.

D. Going forward QF Incentive Mechanism

Our views as stated in the Phase I Bench Analysis have not changed.

E. Miller Hydro Restructuring

VII. OUTSIDE LEGAL EXPENSES FOR CONNECTICUT YANKEE FERC RATE CASE

The Commission should deny CMP's request to defer these expenses, because such expenses should not be recovered from ratepayers on either a current or deferred basis. In its October 13 rebuttal filing, CMP asserts that it has and will incur these legal expenses as part of its obligation to mitigate stranded costs. CMP explains that it purchased power from Connecticut Yankee (CY), much like it purchased power from Regional Waste Systems (RWS). CMP points out that the Commission permitted CMP to recover its costs of litigating its dispute with RWS.

CMP's arguments are without merit. CMP's participation at FERC is not as a purchaser, but as an owner. CY has asked for a substantial increase in decommissioning collections, or an increase to CMP's stranded costs. CMP has decided that other FERC intervenors' allegations of CY imprudence have no merit. (EX-03-05). Ratepayers are already paying for CY's defense against the imprudence allegations. Ratepayers should not also pay for CMP to assist CY in CY's efforts to increase stranded costs.

Indeed, CMP and CY have signed a joint defense agreement, so that its lawyers can confer and strategize without waiving the attorney-client privilege. CMP did not sign a joint defense agreement with RWS. CMP was not a stakeholder of RWS, and did not sit on the RWS Board of Directors. Recovery of CY litigation expenses is not "identical" to recovery of RWS expenses.

At the November 10 technical conference, CMP also stated that, as the principal owner of Maine Yankee (MY), and because of MY's more successful decommissioning performance compared to CY, CMP is uniquely qualified to assist CY in reducing its decommissioning costs. Even if true (and there is no denying that MY's performance has been superior to CY's), CMP's argument fails. If the expenses are for the benefit of CY, then CY should pay for them. Furthermore, we fail to see how MY's experience and superior performance can be used in the FERC rate case to improve CY's decommissioning performance.

VIII. STRANDED COST ALLOCATION AND RATE DESIGN

In its Phase II filing, CMP presented six stranded cost allocation scenarios based on three basic methodologies: (1) equal percentage change to each core class's stranded cost rates; (2) preserving, in full or in part, the existing mitigation for the MGS, IGS and LGS classes; and (3) "bottom-up" allocation based on the 75% energy / 25% demand approach found by the Commission in Docket No. 97-580. Of these, the Staff prefers CMP's equal percentage allocation.

Since March 2000, from time-to-time there have been various customer groups that may have benefited from particular uses of CMP's stranded cost-related items, e.g. from a "linked" standard offer/entitlement arrangement or from mitigation funded by the ASGA. Customers or customer groups have also faced varying levels of energy supply costs, and for most customers these energy costs have been or will soon be increasing. In light of these various factors, the fairest and most stable approach is CMP's method (1), which would apply any stranded cost change on an equal percentage basis to core stranded cost rates. (FN The change would be to *unmitigated* rates for MGS, IGS and LGS).

CMP's method (2) is an attempt to preserve the existing mitigation for MGS, IGS and LGS customers. Mitigation was adopted for these classes to offset their supply prices, which were expected to be high. In contrast, mitigation was not adopted for small commercial or residential customers who, during the mitigation period, were continue as of March 2005 and, thus, the justification for mitigation to certain classes and not to others no longer exists.

CMP's method (3) reflects an overall stranded cost reallocation and would result in widely varying rate changes among customer classes. For instance, the delivery rates of sub-transmission industrial customers would increase significantly while the rates of transmission customers would decrease. Residential and small commercial rates would increase, while rates for all other distribution voltage C&I classes would decrease. Given the supply price increases expected in March 2005, it may not be a good time to also increase delivery rates to achieve an overall stranded cost reallocation.

In addition, the results of CMP's reallocation are inconsistent with results it has presented in other cases. An in-depth review of CMP's application of this method, including a review of the underlying allocators, would be necessary before it could be used.

With respect to rate design within customer classes, CMP's recommended approach follows the basic principles adopted by the rate design stipulation in Docket No. 2001-245. Before commenting on this issue, however, we wish to consider the comments of the other parties.

Respectfully submitted by:

James A. Buckley on behalf of
Advisory Staff